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Smart Municipal Energy Grid within Electricity Market

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ABSTRACT

A smart municipal energy grid including electricity and heat production infrastructure and electricity demand response has been modeled in HOMER case study with the aim of decreasing total yearly community energy costs. The optimal configurations of used technologies (photovoltaic plants, combined heat and power plants, wind power plants) and sizing, with minimal costs, are presented and compared using three scenarios of average electricity market price 3.5 c€/kWh, 5 c€/kWh and 10 c€/kWh. Smart municipal energy grids will have an important role in future electricity markets, due to their flexibility to utilize excess electricity production from CHP and variable renewable energy sources through heat storage. This flexibility enables the levelized costs of energy within smart municipal energy grids to decrease below electricity market prices even in case of fuel price disturbances. With initial costs in the range 0- 3,931,882 €, it has been shown that economical and environmental benefits of smart municipal energy grids are: the internal rate of return in the range 6.87-15.3%, and CO2 emissions in the range from -4,885,203 to 5,165,780 kg/year. The resulting realistic number of hours of operation of combined heat and power plants obtained by simulations is in the range 2,410- 7,849 hours/year.

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KEYWORDS

Smart grid, demand response, district heating, real time pricing.

HIGHLIGHTS

- A smart municipal energy grid has been modeled in HOMER.
- The national electricity grid has been modeled with real time prices.
- Smart municipal grids could utilize excess electricity as their heat source.
- The hours of operation should be obtained with respect to hourly simulations.
- Smart municipal energy grids reduce energy costs below the assumed market price.

ABBREVIATIONS

BGCHP	Biogas CHP
BMS	Biomass
CAPEX	Capital Investment Costs
CHP	Combined Heat and Power
HOMER	Hybrid Optimization of Multiple Energy Resources
IRR	Internal Rate of Return
LHV	Lower Heating Value
NGCHP	Natural Gas CHP
O&M	Operation and Maintenance
OPEX	Operation Costs
PV	Photovoltaic

1. INTRODUCTION

Future energy systems are in transition towards increased flexibility in operation which will bring economic benefits [1]. One of these benefits might be the decrease in the levelized cost of energy, which is a sound basis for final customer pricing. The demand response as a locally available flexibility property, has been shown in [2]. It helps that these decentralized smart multi-energy systems [3, 4] of future become more efficient, environmentally friendly, and reliable [5]. Reliability will be more and more important as the number of natural disasters such as floods will increase in future [6], therefore increasing the need for more resilient smart municipal grids [7, 8].

A possible smart isolated grid configuration with demand response and a biogas combined heat and power plant has economic benefits thanks to its flexibility, which is proven using the Hybrid Optimization of Multiple Energy Resources (HOMER) simulation tool [9]. HOMER defines the levelized costs of energy as the average cost per kWh of useful electrical energy produced by the system, excluding the costs for serving the thermal load. An intermittency friendly system with heat/cold demand and storage, including trading electricity on the market, has been demonstrated for different energy carrier prices in study [10]. A recent study which provides a comparison of the least costly energy storage sizes and technologies [11] cold be useful for integration of higher amounts of locally produced energy into smart municipal energy grids and achieving higher resilience standards. A smart municipal energy grid design and economic response to governmental constraints has been shown using HOMER in [12].

In the article [13], the flexibility of heat and electricity provision from biomass plants is assessed for Germany but not for Serbia, which is why this case study will be carried out in Serbia for the City of Sabac. A technical feasibility study, including the techno-economic analysis of a combined heat and power plant fuelled by biogas, has been carried out for plant "Voganj" in Ruma, Serbia [14]. The problem of excess electricity and heat has been solved with grid connection and food production nearby. Technical details regarding grid connection of a small biogas plant are known from a similar pilot project in the region [15].

The economics of energy production depends significantly on yearly utilization. For heat production only it is hard to run units for more than 2,500–3,000 hours per year [16]; therefore, utilization should mean selling more energy to the national grid within a feed-in tariff scheme [14, 17, 18] or participating in electricity markets. On the other hand feed-in tariff scheme might be insufficient for electricity only utilization [19]. Specific investment costs for the combined heat and power (CHP) plant based on a biogas engine depending on the plant size vary in the range 800-9,000 €/kW$_{el}$ [20-22]. They can be estimated more precisely for each size using the formula from [23]. Operation and maintenance (O&M) costs depend on gas quality 0.01-0.02 €/hour*kW for a liquid gas engine [24] and can also be calculated using the formula in [23]. Resulting levelized costs of heat production from waste/crops vary 3.4-6.6 c€/kWh, and for natural gas are 3.6 c€/kWh [25]. The levelized costs of electricity produced from a biogas CHP plant are 13 c€/kWh$_{el}$, as calculated in [14]. The price of input feedstock including transport varies from 0-175 €/t feedstock [21], for poultry, 2.5 €/t for pig manure, energy maize 38-68 €/t [18], and food waste 40 €/t [26]. Net costs can be calculated by subtracting the feed-in premium from this cost. Therefore, for the community, the feedstock cost may also become negative [26], which could enact a synergetic effect between agriculture and electricity from renewable energy [15]. It is assumed that for the Republic of Serbia the natural gas price is 0.3-0.4 €/Nm3 for a small consumer, while the fee for connection to the gas transport network is 0.1- 0.2 €/Nm3 . A study for the CHP plant in Republic of Serbia [16] has found that the internal rate of return (IRR) is 6.92, with payback period of almost 11 years (discount rate 8%). In another study [14], also for the Republic of Serbia, it has been calculated that the payback period for electricity only with the feed-in tariff is 9.8-11 years, and that it is 4.6 years for electricity and heat sold, but with 15-20% interest ratio.

The lower heating value (LHV) of biogas varies 12.6 - 22 MJ/kg [18, 27]. The gasification ratio varies from 0.2 [t/t] for energetic crops [28] to 0.7 for manure, assuming the average of 0.5 [29]. The carbon content of biogas varies from 25%-45% [18, 22, 27]. Based on emission factors for different energy sources [22] and equipment [29], emission-constrained dispatch might be simulated in HOMER with respect to environmental constraints.

Currently, district heating in Serbia is predominantly based on fossil fuel only heat boilers: natural gas (61%), lignite/coal (20%), and fuel oil (18%); there are no renewable district heating grids in Serbia. There have been two energy licenses for biomass cogeneration issued in the municipalities of Prijepolje and Cajetina. There is about 100 MW of biomass cogeneration with 640 GWh$_{el}$/a of electricity production envisaged by the National Renewable Energy Action Plan [30]. According to this plan, the envisaged share of biomass cogeneration in district heating and cooling amounts to 33% of heat energy produced from additionally commissioned facilities (2009-2020), which is around 570 GWh_{th}/a. The electricity produced in Vojvodina, upper part of Republic of Serbia in 2016 was 27.25 GWh, with insignificant heat production [19]. According to the Law on the Privileged Producer, the feed-in tariffs (8.22-13.26 c€/KWh) are available for electricity production from biomass but not either for heat energy or cogeneration. In the case of biogas, feed-in tariffs are recently increased to 15 c€/KWh for the bigger plants (higher rates for plants under 5 MW) and up to working 8,600 hours/year [19]. In addition, the law says that municipalities are responsible for support schemes such as feed-in tariffs for renewable district heating and cooling. On the other hand, a positive economic outlook should be expected from rural communities – they should benefit economically from the localization of the heating and cooling supply chain, but also from food industry, which has a considerable demand for heating in the winter and cooling in the summer, all of which could be supplied by a smart municipal energy grid. The community, the City of Sabac, has a district heating utility named "Toplana-Sabac" with 72.3 MW capacity. Its heat production is manly based on natural gas (93% of capacity) and a small part on fuel oil (7%). The system supplies heat for about 6,700 households and 600 commercial users.

A case study should include the biomass district heating/cooling demand for a community of around 450 households and 800 kW in other sectors – industry or services. Most economic studies are based on the simplification of an assumed utilization ratio of biogas, natural gas plants, and a feed-in contract to sell electricity at an agreed price [16, 25]. Utilization ratio is a bit lower due to load management in a smart municipal grid [27]. In this article this has been tested in an hourly simulation of distributed generators' economic dispatch under real time prices for the Republic of Serbia, using a biogas plant as a load management unit, in the case of a smaller community in the City of Sabac. The result is the decrease in operation of those generators with similar payback times due to lowered interest rates.

2. SMART MUNICIPAL GRID MODEL: SABAC COMMUNITY

The HOMER simulation tool has been used for modeling and assessing smart municipal energy grid configurations. It has been used a lot for simulations of integration of variable renewable energy sources [31], it is well documented [32, 33], and contains a useful help file. The tool has been used in a number of techno-economic studies for grid connected and islanded operated systems e.g. [9, 12, 34-41].

In the study [36] HOMER was compared to the EnergyPLAN and another self-built tool for assessment of demand response, but without consideration of variable renewable energy sources and heat demand. The high profitability of a smart isolated energy grid based on renewable generation, demand response and biogas CHP plant, has been presented in the case of Congo [9]. HOMER has been used as a planning tool for municipal smart energy grids in Serbia for the purpose of the Covenant of Mayors optimal local energy plan [12, 42], but with fixed national electricity grid tariff and not with real time electricity market prices. For more precision in physical electricity grid modeling, HOMER may be soft-linked with the PowerWorld tool like in [34] or used with DigSilent [43][44]. HOMER might be used to model smaller smart household energy systems like in [45], where heat demand was not assessed but only electricity demand. HOMER has been used to model a pumped hydro storage power plant [46] and therefore will be useful in the future to assess demand response potential of water pumps for advanced agriculture in Macva, the state district surrounding the City of Sabac. In a HOMER study [47] the use of a biogas CHP (BGCHP) plant in combination of a photovoltaic (PV) and wind generator has been shown to be techno-economically optimal in the case of a small energy system autonomous from the national grid. Another HOMER study [48] finds an optimal autonomous microgrid design for Oujda city, Morocco. HOMER with energyPRO or other tools should be further used for thermal process modeling in distribution grids, especially in the systems with heat storage [11].

When it comes to distributed generation, optimal operation algorithm of weekly simulations, with respect to detailed generator efficiency modeling and peak demand minimization of an industrial grid can be found in [49]. Using EnergyPLAN and Matlab, it has been shown [18] that pit storage has an economic advantage over a biomass power plant for peak shaving.

The City of Sabac was selected for the case study of a smart municipal energy grid because of its significance for the research project "CoolHeating". However, any municipality or city in the Republic of Serbia, or in the region, may be considered for future case studies. It has been assumed that a small community consisting of 450 households with heat and electricity demand and industry with a heating/cooling demand of 800 kW shall be supplied during one year. Configuration of the smart municipal energy system has been shown in Fig. 1.

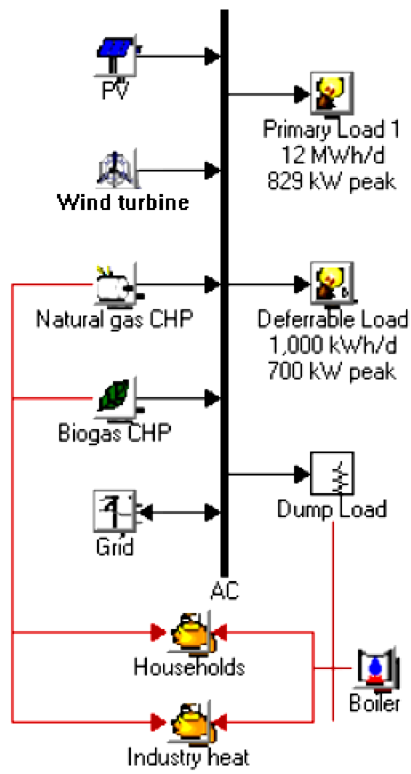


Figure 1 Smart municipal energy grid configuration: PV, Wind turbine, Natural gas CHP generator, Biogas CHP generator, Thermal load: Households, Industry, Primary and deferrable electricity load.

All houses and industry are connected to the national electricity grid and district heating grid which is operated using natural gas boilers. Electricity load is divided into deferrable and non-deferrable (primary) load. Possible investment options are a CHP plant based on biogas or natural gas, photovoltaic (PV), and wind power plants. Also, the option of converting electricity to heat as dump load has been considered [50].

Demand. It is assumed that in a community with the average household of $100m^2$ and 150 kWh_{heat}/ m^2 * yearly demand, the total household demand is 18,480 kWh_{heat} /day. This is comparable to yearly heat consumption in Austria [50], without hot water, but a sensitivity analysis may be done since other values of yearly consumption are possible. The heat duration curve has been obtained using the degree-day method and average yearly temperature. Additionally, besides heat demand, hot water demand may be also considered in future work [26]. For industrial heat/cold demand, it is assumed that there are 24 working hours 5 days a week during 53 weeks with the constant demand of 800 kW and random day-to-day variability of 10% and hour-to-hour variability of 10%. This is an optimistic assumption since such high utilization rates are not typical for every industry. Besides heating, other or more specific industry heat use options with different demand characteristics may be considered in future, e.g. drying in wood and agriculture industries, or cooling in food industry [27].

Electricity demand is assumed to be 10.5 MWh/a per household, resulting in total community demand of 13 MWh/d, of which 12 MWh/day are assumed as primary (nondeferable) load, and 1 MWh/day as deferrable load. The electricity demand assumption is higher than average from around 2.4 M households in the Republic in Serbia and residential consumption of around 13.8 TWh/a in the year 2014 [51]. The deferrable load is considered to be max 700 MW, with the ability to "store" max 6,000 kWh.

Generators. For the PV array lifetime of 15 years, it is assumed that the derating factor is 80% and the slope is 32 degrees. The assumed costs are the capital costs of 740€/kW, the replacement of 400€/kW, and operation and maintenance (O&M) of 15€/kW*year, which is low in comparison to example investment costs of 1,231 – 1,403 €/kW, but similar to O&M costs of 12.5 – 15.1 €/kW*year [52]. Information on recent investment costs in Denmark and the United Arab Emirates supports this cost assessment, because in these countries costs were even lower.

Solar resource inputs per month are given in Table 1 with the average of 3.47 kWh/m^2*day. For the wind turbine (S3.7), it is assumed that it has a lifetime of 20 years, hub height of 33.5m, rated power of 1.8 kW, capital and replacement costs of 3,000€, and O&M costs of 30€/year per turbine. The assumed capital costs are in the range of 1,451 – 1,836 €/kW, while the assumed O&M cost are below 35.6 – 47.1 €/kW/year [52].

Table 1 shows the wind resource yearly average of 3.6 m/s, and the solar resource data obtained from [53].

Table 1 Solar and wind resource inputs

Month	Clearness Index	Daily Radiation ($kWh/m^2/d$)	Wind Speed (m/s)
January	0.410	1.310	5.319
February	0.482	2.240	2.890
March	0.473	3.220	3.209
April	0.466	4.250	2.998
May	0.487	5.280	3.041
June	0.492	5.700	2.141
July	0.515	5.770	3.123
August	0.525	5.120	3.492
September	0.498	3.780	2.539
October	0.463	2.440	3.992
November	0.393	1.380	5.841
December	0.375	1.040	4.590

For the natural gas CHP (NGCHP) plant, it is assumed that it has a 60,000 working hour lifetime, the minimal load ratio of 30%, and the heat recovery ratio of 70%. The costs of NGCHP for different sizes are given in Table 2.

Table 2 Natural gas and biogas CHP costs

	Natural gas		Biogas	
Size (kW)	Capital / Replacement (€)	O&M (€/hr)	Capital / Replacement (€)	O&M (€/hr)
75	81,337	0.01	661,652	0.035
150	138,654	0.01	1,039,684	0.035
250	205,421	0.01	1,450,597	0.035
500	350,177	0.01	2,279,388	0.025
1,000	596,939	0.01	3,581,705	0.025
2,000	1,017,589	0.006	5,628,095	0.025
3,000	1,390,191	0.006	7,331,163	0.013
5,000	2,059,621	0.006	10,228,649	0.013

Assumed efficiency curves of the natural gas and biogas plant for different levels of load are shown in Fig 2.

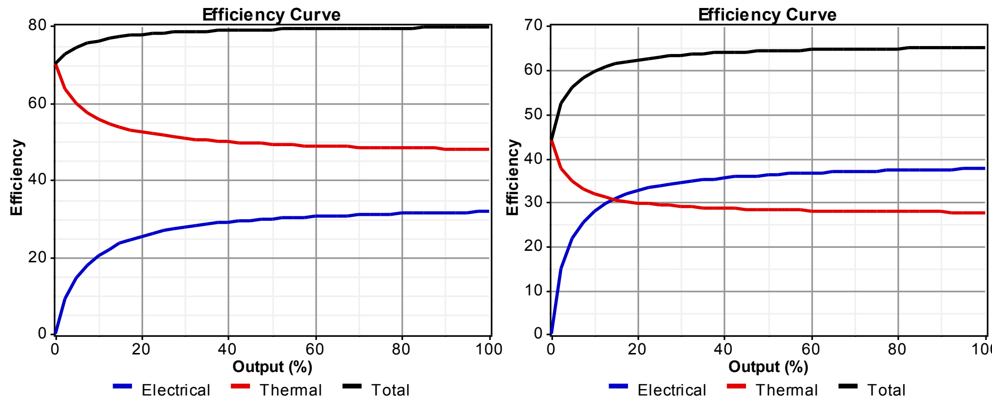


Figure 2 Natural gas (left) and biogas (right) CHP efficiency curve

The assumed maximal overall efficiency of NGCHP plant at nominal output operation is around 80%.

It is assumed that the biogas CHP (BGCHP) plant has a lifetime of 60,000 working hours, minimal load ratio of 30%, and heat recovery ratio of 44%. Typical costs for different sizes of biogas CHP plants (including engine and all facilities costs) are also given in Table 2.Those costs for the BGCHP are within or above the values 1,935 – 6,723.5 €/kW, presented in [52].

Capital and replacement costs are the same for the purpose of simplicity. O&M specific costs reduce with plant size.

The assumed efficiency curve for the BGCHP plant is lower assuming parasite heat (30%) and power consumption (8%) of the digester [25], as shown in Fig. 2. The data from the biogas plants in operation from [54] are used to calibrate feedstock consumption for biogas production and realistic electricity and heat production. The heat demand of the digester can be modeled in more detail as a separate heat demand with a seasonal effect [27]. Process related details for biogas plants sized 75-500 kW_{el} may be found in [21].

The maximal overall energy efficiency of the BGCHP plant is around 65% at nominal output. Besides the modeled CHP plant based on the engine, a gas turbine [55] may also be considered in future techno-economic studies.

Optimization search space among different generators and different sizes is shown in Table 3.

Table 3 HOMER optimization search space (PV Array - photovoltaic array, S3.7 - wind turbine, NGCHP - natural gas CHP, BGCHP - biogas CHP, Grid - national electricity grid connection

	PV Array (kW)	S3.7 (Quantity)	NGCHP (kW)	BGCHP (kW)	Grid (kW)
1	-	-	-	-	1,000
2	250	10	75	75	
3	500	25	150	150	
4			250	250	
5			500	500	
6			1,000	1,000	
7			1,500	1,500	

The total number of possible system designs is 3*3*7*7 = 441. Although it is possible to use continuous variables in optimization, the discrete decision variables are an inherent feature of the HOMER tool. In order to improve accuracy, one may decide to use more decision variables around an optimal point or repeat the procedure, but this should be traded with computation time.

Energy carriers and their prices. It is assumed that the national electricity grid real-time price is on average 3 c€/kWh, 5 c€/kWh and 10 c€/kWh. Bearing in mind that wholesale electricity prices in SEEPEX (Belgrade power exchange) auctions start with the daily average of 2.5 c€/kWh in March 2016 and up to 10 c€/kWh in January 2017, the price assumptions above are realistic, although it has to be mentioned these are still low volume auctions in comparison to overall load. The hourly price is dependable on wholesale electricity market prices. The power density function for the average price of 5 c€/kWh is shown in Fig. 3. For other prices, the power density function has been translated along the price axis (horizontal x-axis) assuming the same distribution.

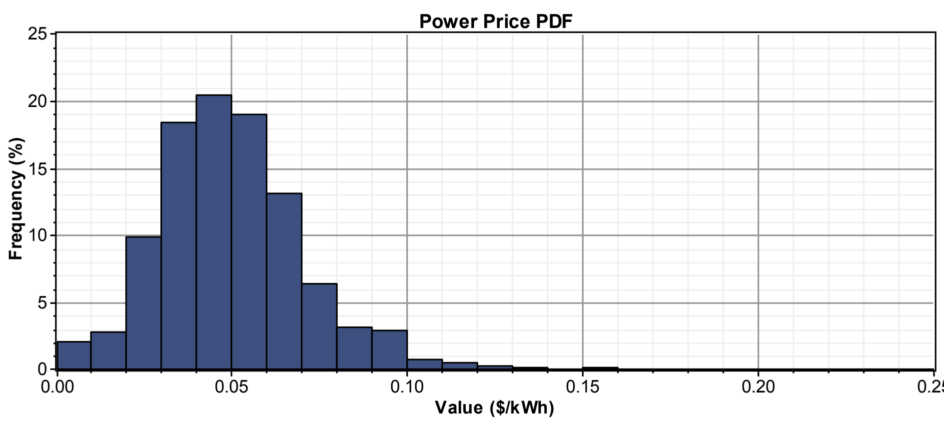


Figure 3 Power density function of the national electricity grid hourly price.

For natural gas it is assumed that the lower heating value is 45 MJ/kg [56], density 0.79 kg/m3, carbon content 67%, and sulphur content 0.33%. Regarding biogas, it is assumed that there is a daily average of 1,000 t of manure and organic waste input. The assumed gasification ratio is 0.5 kg of gas/kg feedstock, the assumed lower heating value of biogas is 18.5 MJ/kg, and its carbon content is 38%. The assumed lower heating value of biogas and carbon content are within the range of 21.5-23.5 MJ/kg and 15-45% [27]. Detailed methane production from different feedstock types may be considered in the future [27]. Maximal manure feedstock costs for a different feed-in support should not exceed 3-7€/t [17]. Farm distance from the BGCHP plant and different ownership models (third party or farmers' ownership) result in different economics of the smart municipal grid, which might be modeled as the increase in the price of feedstock [57], even in more detail by using geographic information system tools [58].

The sensitivity analysis search space of the prices of natural gas and subvention feedstock are given in Table 4.

Table 4 Sensitivity inputs space

Biomass (€/t)	Natural gas (€/Nm3)
-10	0.1
-5	0.2
0	0.3
5	0.4
10	0.5

The search space for sensitivity analysis consists of 5*5 =25 options, which together with 441 possible system design options, creates 11,025 yearly simulations to run during optimization.

The grid purchase/sale capacity of 1,000 kW is assumed.

When it comes to the economic situation, it is assumed that the annual real interest rate is 5%, and the project lifetime is 30 years.

The overall biogas production potential in the Republic of Serbia, and for Vojvodina have been estimated [59, 60] but so far no exact details for the City of Sabac have been available. Based on the first assessment, the availability of feedstock from animal manure for the City of Sabac and the district of Macva is given in Table 5. This assessment has to be done with more detail including other different feedstock and their biogas yield detail [21], as well as other available sources of dry biomass [61].

Table 5 Available feedstock for biogas production from manure in the Macva state district and City of Sabac.

Area/Type	Cattle	Pigs	Sheep	Poultry	Σ Feedstock [t/d]
Macva state district	80,283	400,391	161,878	1,060,996	3,591
City of Sabac	26,837	116,881	36,233	289,520	1,117

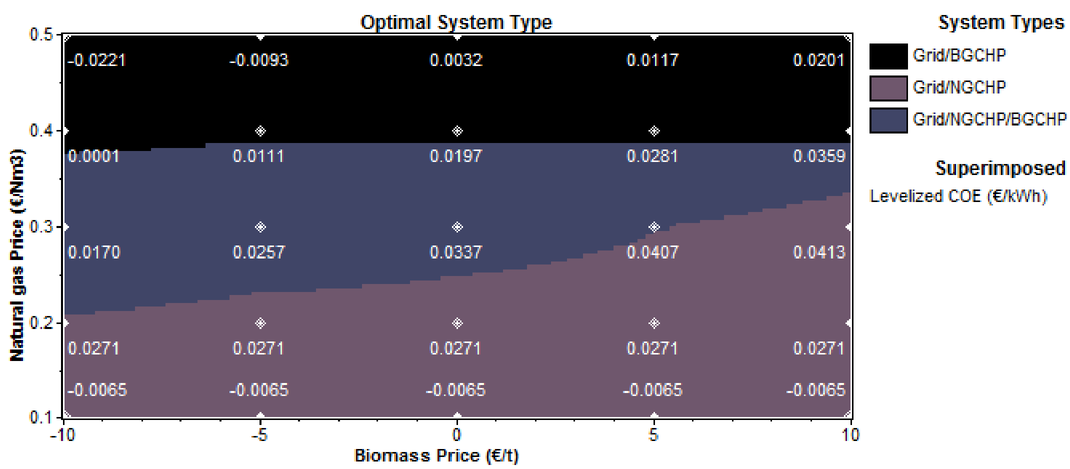
When it comes to biomass resource input, the assumed constant annual availability of feedstock is 1,000 t/d for the first case, but in the future some more realistic assessment needs to be made, due to availability and possibility of seasonal scheduling.

3. RESULTS

The optimal system structure graph as a result of HOMER simulations of sensitivity variables (natural gas price and biomass price) is shown in Fig. 4-6 for differently assumed national grid electricity price, according to the wholesale market price. The additionally levelized cost of energy for municipal grid customers (€/kWh) has been superimposed.

For the average national grid electricity price of 5c€/kWh, there are three (3) viable optimal system structures (Fig. 4):

1. the combination of the national electricity grid with a natural gas generator (Grid/NGCHP);
2. the combination of the national electricity grid with a biogas generator (Grid/BGCHP);
3. the combination of the national electricity grid with a natural gas generator and a biogas generator (Grid/NGCHP/BGCHP).

4. 

5. Figure 4 Optimal system structure for national electricity grid average price of 5c€/kWh.

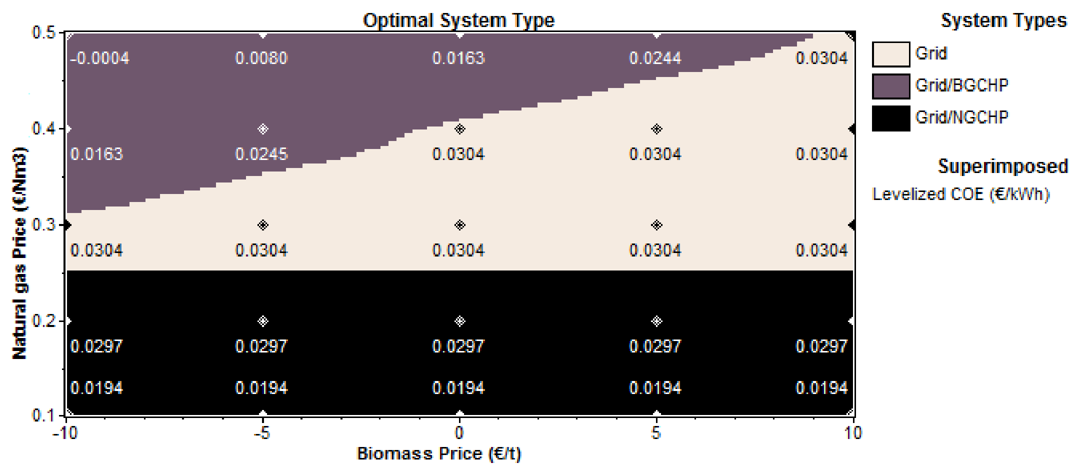
A natural CHP in combination with the national electricity grid is the optimal system structure for the natural gas price of 0.2 €/Nm3, and up to 0.4 €/Nm3, depending on the price of biomass (lower area of the graph). The negative levelized cost of energy in the case of extremely low natural gas prices of 0.1 €/Nm3, shows it is profitable to sell electricity from the NGCHP to the national grid. In the case the low natural gas price of 0.2 €/Nm3, the levelized cost of energy may decrease below the average national grid price. The upper triangle of the space defined with moderate natural gas prices 0.2-0.4 €/Nm3 shows it is optimal to build a BGCHP besides a

NGCHP, while for the prices above 0.4 €/Nm3 NGCHP is not profitable. The levelized costs of energy in all cases are below the national grid average price.

The calculated marginal cost of heat from the BGCHP is 0.5 c€/kWh, and from the NGCHP it is 9 c€/kWh in the [0.3 €/Nm3, 5 €/t] scenario. These marginal costs are calculated based on the capacity factors obtained through simulation: 72% for the BGCHP and 25% for the NGCHP.

For the average national grid electricity price of 3c€/kWh (Fig. 5), there are three viable (3) optimal system structures:

1. the national electricity grid (Grid);
2. a combination of the national electricity grid with a natural gas generator (Grid/NGCHP);
3. a combination of the national electricity grid with a biogas generator (Grid/BGCHP).



4. Figure 5 Optimal system structure for national electricity grid average price of 3c€/kWh.

The decreased national electricity grid average price of 0.3 c€/kWh resulted in the fact that the national grid became one of the optimal system types. If the natural gas price is 0.25-0.5 €/Nm3, the optimal system type depends on the biomass price (the middle triangle of the graph). The construction of the BGCHP is advised for the natural gas price above 0.3 €/Nm3, in the case of the subsidized biogas price or above the natural gas price of 0.4 €/Nm3 and 0.5 €/Nm3 for higher biomass prices (the upper triangle). Below the natural gas price of 0.25 €/Nm3, the combination of the national grid and the NGCHP is optimal (the lower rectangle). The levelized costs of energy could be decreased based on the construction of the NGCHP or the BGCHP.

For the average national grid electricity price of 10c€/kWh, Fig. 6, there are eight (8) viable optimal system structures:

1. a combination of the national electricity grid with a natural gas generator (Grid/NGCHP);

2. a combination of the national electricity grid with a natural gas and a biogas generator (Grid/NGCHP/BGCHP);
3. a combination of the national electricity grid with a PV and natural generator (Grid/PV/NGCHP);
4. a combination of the national electricity grid with a PV,natural, and biogas generator (Grid/PV/NGCHP/BGCHP);
5. a combination of the national electricity grid with a wind and natural gas generator (Grid/Wind/NGCHP);
6. a combination of the national electricity grid with a wind, natural gas and biogas generator (Grid/Wind/NGCHP/BGCHP);
7. a combination of the national electricity grid with a PV, wind and natural gas generator (Grid/PV/Wind/NGCHP);
8. a combination of the national electricity grid with a PV, wind, natural and biogas generator (Grid/PV/Wind/NGCHP/BGCHP).

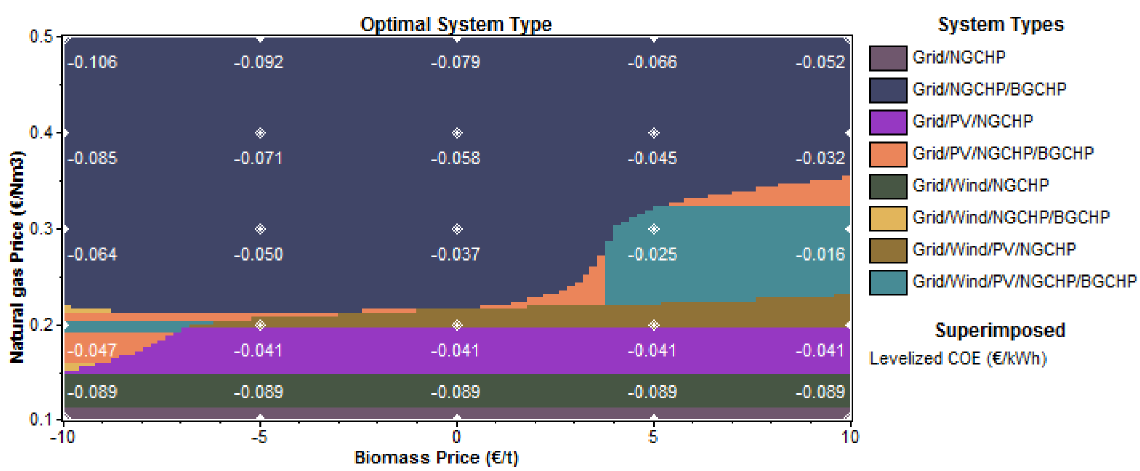


Figure 6 Optimal system structure for national electricity grid average price of 10c€/kWh.

Starting from the natural gas price of 0.1 €/Nm3 for all biomass prices, the combination of the national electricity grid with a natural gas generator (Grid/NGCHP) is the optimal system structure, followed by the combination of the national electricity grid with a wind and natural gas generator (Grid/Wind/NGCHP) first, and later, when the natural gas price reaches 0.2 €/m3, the combination of the national electricity grid with a PV and biogas generator (Grid/PV/BGCHP). The natural gas price of 0.35 €/Nm3 is still competitive in three system combinations: the combination of the national electricity grid with a PV, wind and natural gas generator (Grid/PV/Wind/NGCHP) shown at the right lower triangle, the combination of the national electricity grid with a natural gas and biogas generator (Grid/NGCHP/BGCHP), and the combination of the national electricity grid with a PV, natural and biogas generator

(Grid/PV/NGCHP/BGCHP). Above the price of 0.35 €/Nm3, natural gas generators and biogas generators compete, differently sized for different price combinations.

All design cases are profitable for the national electricity grid with the average price of 10c€/kWh and higher because levelized costs of energy are negative.

3.1. Rate of return

The economics of different system configurations for the national electricity grid average price of 5c€/kWh are shown in Table 6.

Table 6 Economics comparison of different system configurations with base configuration for the 5c€/kWhel average price and four combinations of biomass and natural gas prices.

System characteristics	Base	S1	S2	S3	S4	S5
Biomass [€/t]	-	-10	-5	0	5	10
Natural gas [€/Nm3]	-	0.3				
NGCHP [kW]	-	500	500	500	500	1,000
BGCHP [kW]	-	1,000	1,000	1,000	1,000	-
Grid [kW]	1,000	1,000	1,000	1,000	1,000	1,000
Initial cost [€]	-	3,931,882	3,931,882	3,931,882	3,931,882	596,939
Total cost [€]	11,592,836	9,133,686	9,763,992	10,350,609	10,861,921	10,902,640
Present worth [€]	-	2,459,154	1,828,847	1,242,229	730,917	690,197
Annual worth [€/year]	-	159,971	118,969	80,809	47,547	44,898
Return on investment [%]	-	10.40%	9.41%	8.45%	7.56%	13.9%
Internal rate of return [%]	-	11.10%	9.58%	8.15%	6.87%	15.3%
Simple payback [years]	-	5.16	5.62	6.19	7.04	5.63
Discounted payback [years]	-	6.13	6.77	7.6	8.9	6.78
Hours NGCHP	-	2,410	2,410	2,410	2,410	4,327
Hours BGCHP	-	7,849	7,484	7,031	6,331	-

The first two rows show the assumed biomass and natural gas prices. The next three rows show the resulting optimal system structures for the assumed prices. The base system, used for all comparisons, consists only of the connection to the national electricity grid (Grid). Other scenarios (S1-5) are:

- a combination of the national electricity grid with a natural gas generator (Grid/NGCHP);

- a combination of the national electricity grid with a natural gas and biogas generator (Grid/NGCHP/BGCHP).

The selected sizes of biogas generators are 1,000 kW and 500 kW for natural gas generators. The sixth row presents initial costs, which are capital investment costs (CAPEX) for equipment. Assuming that the grid exists, the investment cost for the grid is zero. The total cost, the sum of CAPEX and operation costs (OPEX) over project lifetime, are shown to be lower in scenarios S1-5 than in the base scenario. This results in the return of investment 7.56-10.4% for the Grid/NGCHP/BGCHP system structure, and 13.9% for the Grid/NGCHP system structure. The discounted payback is 6.13-8.9 years, showing that it is sensitive to economic subsidies for biomass. Further calculations may show a desired level of subsidy for biomass.

3.2. Hours of operation

The realistic hours of operation for NGCHP and BGCHP plants, obtained from 8,760 hourly simulations over one year, are shown in the last two rows of the Table 8. The capacity factor is 0.7-0.9 for the profitable BGCHP plant, and 0.25-0.5 for the profitable NGCHP plant. They are not constant but rather dependable on many system design factors. At breakpoints, the hours of operation of one generator structure may suddenly drop to zero, resulting in a jump of the hours of operation of other generator types. Further analysis may show that the BGCHP plant is more profitable than the NGCHP plant only in the higher hours of operation. Those realistic operation conditions should be used for the development of detailed business plans for the future expansion of small municipal distributed grids within the electricity market.

3.3. Environmental benefits

Fig. 7 shows that smart municipal energy grids entail significant environmental benefits, which should not be neglected in the elaboration of their techno-economic optimality.

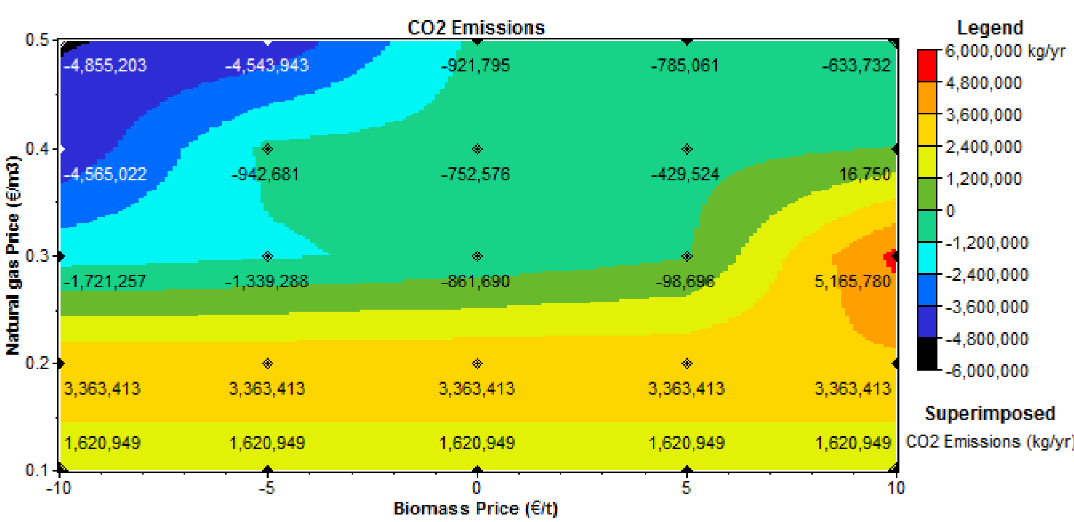


Figure 7 Surface plot of the smart municipal grid yearly CO_2 emissions for the 5c€/kWh average electricity market price and 25 different fuel price scenarios.

The yearly CO2 emissions from the smart municipal grid obtained from the base scenario of 7,586,505 kg/year, decrease with investments in all 25 scenarios. This is due to equivalent emission from the electricity grid in the Republic of Serbia, which is significant. The highest emission savings are shown in the scenario with high natural gas costs and strong policy support for biomass, resulting in negative total equivalent emissions of -4,855,203 kg/year, including the exported renewable energy.

4. CONCLUSION

Many municipal grids of today operate connected to the national electricity grid without investment in distributed generation. This article has shown that investment in a smart municipal grid infrastructure could decrease the levelized cost of energy in the municipal grid below the national electricity grid average market price, due to smart municipal grids' flexible operation and optimal sales and purchases. Furthermore, the sensitivity analysis has shown that this would not change even in case of disturbances of natural gas prices or biomass prices.

Although the levelized cost of energy in the municipal grid could decrease with optimal investments decisions, the payback periods of the smart municipal infrastructure may additionally decrease with a properly designed local economic support energy policy for the biomass resource.

Moreover, the environmental benefits of smart municipal grids are substantial, due to high equivalent emission from the national electricity grid.

More detailed results from this paper show that the hours of operation of the CHP plant depend on various system design factors. Therefore, during the planning process it is advised not to assume any constant values for hours of operation (obtained exogenously), but rather obtain them as the result of the optimal investment decision and realistic operation. The hours of operation should not be kept at a constant level in techno-economic feasibility studies when making the investment decision.

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